

TECHNICAL facts

Sequestration

4/2006

U.S. DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY
NATIONAL ENERGY TECHNOLOGY LABORATORY



SYSTEM ANALYSES OF CO₂ CAPTURE TECHNOLOGIES INSTALLED ON INTEGRATED GASIFICATION COMBINED CYCLE PLANTS

Background

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In the United States, electric power generation is the largest contributor to the buildup of atmospheric carbon dioxide (CO₂). Coal fuels more than half of the power generation and typically produces the cheapest electricity among the fossil fuels. However, relative to CO₂ generation, coal suffers from an inherent disadvantage, since it produces more CO₂ per kWh of electricity than other fuels. The fact that many coal power plants are old and inefficient adds to the problem. Electricity consumption is expected to grow (see Figure 1); and because it is our most abundant fossil fuel, coal will continue to be the dominant energy source. Therefore, coal-based power generation can be expected to provide an even greater CO₂ contribution in the future. Due to the potential for CO₂ to contribute to global climate change, technology and policy options are being investigated to mitigate CO₂ emissions from coal-based power plants.

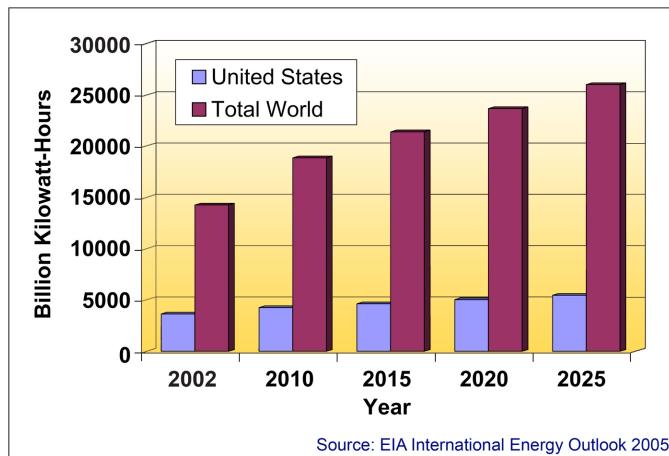


Figure 1. World Electricity Consumption

Current research and development (R&D) efforts are largely focused toward implementation of Integrated Gasification Combined Cycle (IGCC) power generation in conjunction with carbon capture and sequestration. Technologies related to capturing CO₂ from IGCC plants for subsequent storage are rapidly emerging. Each of these options carries with it costs that plant operators, and ultimately consumers, must bear. Thus, economic factors will be a major consideration when deciding which technologies have the potential to be deployed commercially and, hence, justify receiving federal funding for continued development.

R&D personnel are investigating a wide range of CO₂ capture options. Systems analyses and economic modeling of these new and emerging processes are crucial to providing sound guidance to this effort. Ongoing systems analyses are being performed on NETL in-house R&D CO₂ capture technologies, as well as for processes being developed by universities and industry. Some of these studies, particularly on developed technologies, are performed by engineering firms and provide detailed, high quality estimates. Other studies on emerging technologies are of lesser detail, due to limited availability of supporting information. Nevertheless, these studies are very valuable for helping to guide R&D activities.

NETL has developed an economic model that enables evaluation of “Nth plant” costs for various CO₂ capture, pipeline transport, and geologic storage technologies. The completion of additional studies allows the technical and economic merit of new technologies to be directly compared to a variety of other options. As R&D advances are made and new data emerges, the model is updated to incorporate this information, thus keeping the results generated by the model as current as possible; and this document is updated annually to reflect these advancements. Similar fact sheets are also available for pulverized coal and advanced combustion CO₂ capture concepts.

Project Objective

Systems analyses have multiple goals: (1) to put emerging technologies being developed at the laboratory/bench scale into a systems context (i.e., commercial scale power plant), (2) to screen out unpromising projects before significant resources are spent on them, and (3) to provide guidance to NETL technology managers and researchers working on more promising projects, so that they can concentrate on the aspects of the process that will contribute most to its success.

Cases

Various cases have been evaluated (see Table 1), and results of these studies are discussed below. All cases are evaluated assuming 400 MWe net power generation, 65% capacity factor, Illinois #6 bituminous coal, 90% CO₂ capture, CO₂ compression to 2,200 psia, transported 50 miles and stored in a saline formation.

Base Case – This is the case to which other cases are compared and is based on a design (*Case 3B*) presented in a 2000 DOE/EPRI study [1]. The plant design approach is market-based, and the configuration reflects current information and design preferences—use of a single combustion turbine coupled with a heat recovery system that generates steam for use in a single steam turbine generator. The gasifier chosen for this configuration has a cryogenic air separation unit (ASU) in place to supply 95% oxygen to the gasifier. Raw fuel gas exiting the gasifier is cooled and cleaned of particulates before being routed to a series of raw gas coolers. After desulfurization in an amine unit, the fuel gas is reheated and fired in the combustion turbine. Gross power output for this plant is 445 MWe [1].

Table 1 - Cases Evaluated

Case	Description
1	Selexol Scrubbing (2000 Study)
2	Advanced Selexol Scrubbing (2005 Study)
3	Advanced Selexol Scrubbing with Co-Storage of CO ₂ /H ₂ S
4	Advanced Selexol with Oxygen-Selective Ion Transport Membrane (ITM) and Co-Storage
5	Water Gas Shift (WGS) Membrane with Co-Storage
6	Water Gas Shift/Oxygen Membranes with Co-Storage
7	Chemical Looping with Co-Storage

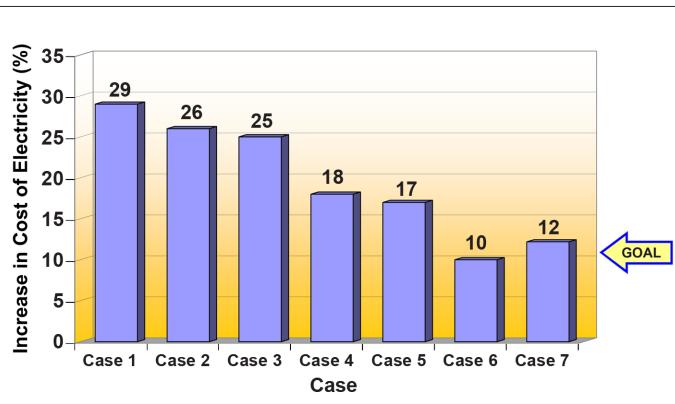


Figure 2. Percent Increase in Cost of Electricity

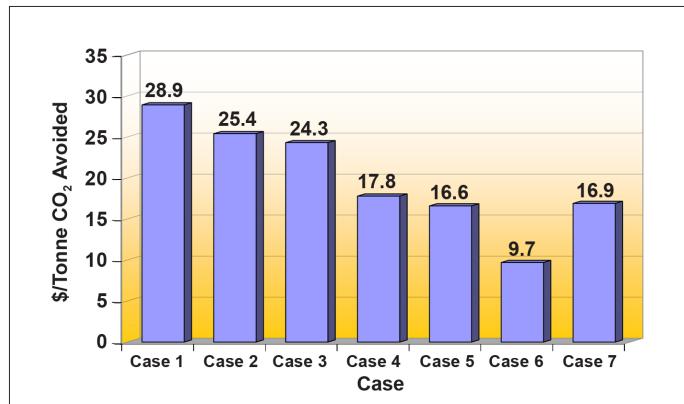


Figure 3. CO₂ Avoidance Cost

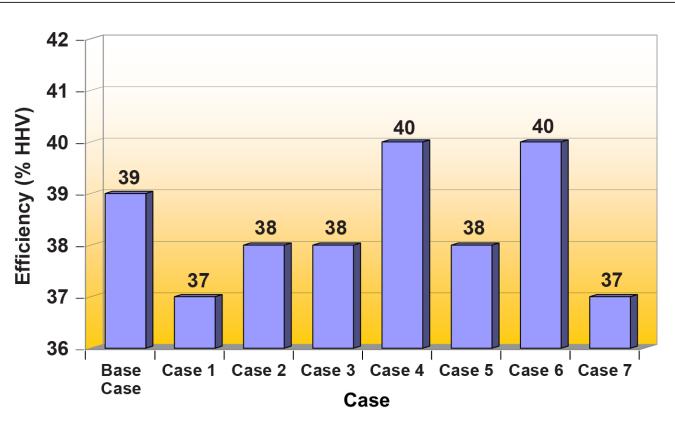


Figure 4. Efficiencies

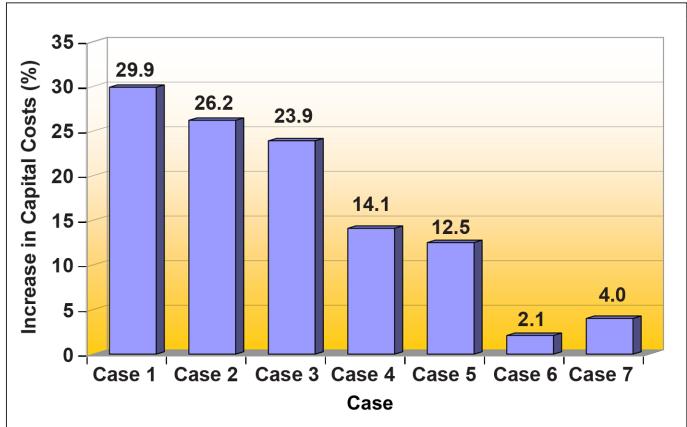


Figure 5. Percent Increase in Capital Costs

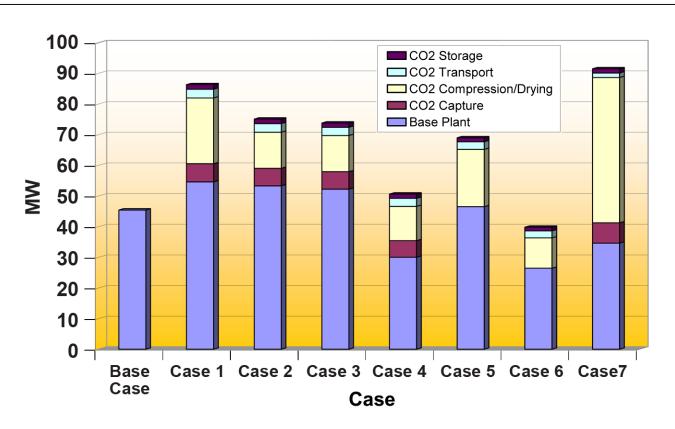


Figure 6. Auxiliary Power Loads

Case 1 – Design basis is the same as the Base Case except that a double-staged Selexol unit is added to capture 90% of the CO₂ in the fuel gas as well as H₂S. Raw fuel gas exiting the gasifier is cooled and cleaned of particulate by a metal candle filter before being routed to a series of water-gas shift reactors (to create a concentrated CO₂ stream by converting CO and H₂O to H₂ and CO₂) and raw gas coolers. Once concentrated, CO₂ is removed in the Selexol unit along with more than 99.7 percent of the H₂S. The captured H₂S is subsequently concentrated and processed in a Claus plant and tail gas treating unit (TGCU) to produce an elemental sulfur product that may be sold. CO₂, exiting the Selexol unit at 25 psia, is dried and compressed to supercritical conditions for pipeline transport. Clean fuel gas from the Selexol unit, now rich in H₂, is fired and expanded in the combustion turbine. Waste heat is recovered from this process and used to generate steam that feeds a steam turbine. Gross power output for this case is 484 MWe [1].

Case 2 – Design is the same as Case 1 except that advanced Selexol replaces traditional Selexol for CO₂ and H₂S capture. This advanced sorbent is assumed to be capable of regenerating CO₂ at a pressure (175 psia) greater than traditional Selexol allows (25 psia). A higher regeneration pressure results in reduced parasitic load from compression. The gross power output for this case is 472 MWe [2].

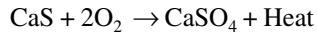
Case 3 – Design basis is the same as Case 2 except co-sequestration of CO₂ and H₂S is carried out. Based on a 2004 IEA GHG report, “there are no technical barriers with co-sequestration of these components.” Thus, this case assumes no Claus plant or tail gas treating unit (TGTU) and no increase in compression and transmission capital costs. Gross power output is 471 MWe [3].

Case 4 – A similar configuration as Case 3 except that an oxygen-selective ion transport membrane replaces a cryogenic ASU as the source of oxygen to the gasifier. A 41% decrease in ASU capital cost and 54% decrease in ASU parasitic loads are assumed. Gross power output for this case is 448 MWe.

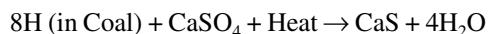
Case 5 – Same configuration as Case 1 with two modifications: 1) a hydrogen-selective Water Gas Shift (WGS) membrane reactor replaces traditional WGS reactors for conversion of CO to CO₂, and 2) co-sequestration of CO₂ and H₂S is employed. As syngas passes through the WGS membrane reactor, H₂ passes from the retentate side of the membrane to the permeate side. As such, by LeChatliers Principle, the WGS reaction equilibrium is shifted toward further conversion of CO to CO₂, resulting in a concentrated stream of CO₂ and H₂S. Since co-sequestration is being utilized, sulfur removal equipment (Selexol, Claus, TGTU) is not necessary. Gross power output for this case is 467 MWe.

Case 6 – Same design basis as Case 5 except that an oxygen-selective ion transport membrane replaces a cryogenic ASU as the source of oxygen to the gasifier. Gross power output for this case is 438 MWe.

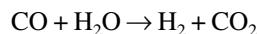
Case 7 – Chemical looping, through a coupled solid reducer and oxidizer, is used to indirectly provide the oxygen for the gasification of coal and to capture CO₂. The oxidizer is designed to capture oxygen from air utilizing a stream of recirculated solids. The chemistry in the oxidizer is:



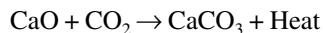
The reducer then produces a medium-Btu gas by reducing CaSO₄ in the presence of coal by the following reactions:



A second process occurring in the reducer is the water-gas shift reaction:



Finally, the CO₂ is captured in the reducer according to the following reaction:



The medium-Btu fuel gas and entrained solids stream leaving the reducer enter a particulate removal device, where the solids, now rich in CaCO₃, are separated from the gas. A calciner regenerates CaO and CO₂ from the CaCO₃. The cleaned fuel gas, which is mostly hydrogen, serves as the feed stream to the Power Generation System. Power production is provided by a single train gas turbine with a heat recovery steam generator and an 1,800 psig/1,000 °F /1,000 °F steam cycle. Gross power output for this case is 492 MWe [4].

References

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4. *Greenhouse Gas Emissions Control by Oxygen Firing in Circulating Fluidized Bed Boilers*, Alstom Power, Inc., May, 2003.